Progress Energy

May 9, 2012

Ms. Jocelyn Boyd
Clerk/Administrator
South Carolina Public Service Commission
Post Office Drawer 11649
Columbia, South Carolina 29211

Re: Docket No. 2012-1-E

Dear Ms. Boyd:

Enclosed for filing in the subject docket are the direct testimonies of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., witnesses Bruce P. Barkley and Dewey S. Roberts, II. In accordance with Commission directive in Docket No. 2005-83-A, also enclosed is a Notice of Filing. All parties of record have been served.

Very truly yours,

Len S. Anthony/mhm

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

cc: Mr. John Flitter
All Parties of Record

Enclosure

STAREG2522

BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

DOCKET NO. 2012-1-E

In the Matter of:

Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., Annual Review of Base Rates For Fuel Costs	)))	**CERTIFICATE OF SERVICE**

I, Len S. Anthony, hereby certify that Progress Energy Carolinas, Inc.'s Direct Testimonies of Witnesses Bruce P. Barkley and Dewey S. Roberts, II have been served on all parties of record either by hand delivery, email or by depositing said copy in the United States mail, postage prepaid, addressed as follows, this the 9th day of May, 2012:

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STAREG2522

STATE OF NORTH CAROLINA	)	
	)	
	)	**VERIFICATION**
	)	
	)	DOCKET NO. 2012-1-E
COUNTY OF WAKE	)	

PERSONALLY APPEARED before me, Bruce P. Barkley who, after first being duly sworn, said that he is Manager – Fuel Forecasting and Regulatory Support at Progress Energy Carolinas, Inc. and as such is authorized to make this verification; that he has read the foregoing Testimony and knows the contents thereof; and that the same are true and correct to the best of his knowledge, information, and belief.

Bruce P Barkley

BRUCE P. BARKLEY

Sworn to and subscribed before me,
this the 9th day of May, 2012.

Marsha H. Manning

Marsha H. Manning, Notary Public

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG2522

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2012-1-E
DIRECT TESTIMONY OF PROGRESS ENERGY CAROLINAS, INC.

WITNESS BRUCE P. BARKLEY

Q. **Please state your name, address, and position.**

A. My name is Bruce P. Barkley and my business address is 410 S. Wilmington Street, Raleigh, North Carolina. I am the Manager–Fuel Forecasting and Regulatory Support for Progress Energy Carolinas, Inc. ("PEC" or "Company")

Q. **Please describe your educational background and professional experience.**

A. I hold a Bachelor of Science Degree in Business Administration from the University of North Carolina and an MBA from Wake Forest University. I am a licensed CPA. I joined Progress Energy in the Regulatory Services Section in 2001 and transferred to my current position in the Fuels and Power Optimization Department in 2005 where I am currently responsible for fuel forecasting, fuel reporting and associated regulatory matters.

Q. **Have you previously presented testimony regarding fuel clauses?**

A. Yes, I have testified in PEC's 2003-2011 fuel cost proceedings before the Public Service Commission of South Carolina ("PSCSC") and in numerous fuel cases before the North Carolina Utilities Commission.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to:

- Describe PEC's fuel procurement practices and costs for the historical period under review in this proceeding, March 2011 through February 2012, and support the reasonableness of these costs.
- Present projected fuel costs through June 2013.

- Recommend fuel factors to be effective July 1, 2012 through June 30, 2013.

My testimony will include a review of historical and projected environmental costs and a recommended rate for recovery of these costs. The environmental portion of the fuel rate includes the cost of ammonia and limestone used in the process of reducing sulfur dioxide (SO_2) and nitrous oxide (NO_x) emissions and the cost of SO_2 and NO_x emission allowances. I will provide twelve exhibits to support my testimony.

Q. Please summarize key fuel cost and inventory information for the review period.

A. Barkley Exhibit No. 1 summarizes PEC's fossil fuel costs for the review period, including quantities purchased and consumed and inventory levels. As projected in last year's proceeding, PEC's delivered cost of coal (transportation cost plus the cost of coal itself) for the year ended February 29, 2012 increased. The increase was approximately $10 per ton (12%), as compared to the prior review period, to $91.11 per ton. This increase in delivered coal price versus the prior review period was equally attributable to the cost of coal and to the cost of coal transportation. Transportation costs increased due to: 1) higher oil costs which were passed along by PEC's traditional suppliers; and 2) PEC purchasing coal from the Illinois Basin (ILB) and Northern Appalachia (NAPP) which are farther from PEC's generating plants than is the traditional source of supply from Central Appalachia (CAPP). Coal from these more distant sources is currently less expensive than CAPP coal and more than offsets the increased transportation costs. I will discuss this further later in my testimony. Coal costs increased as compared to the review period ended February 28, 2011, primarily as a result of contract expirations.

The average price of natural gas purchased during the current review period decreased by $.85 per million British Thermal Unit ("mmbtu") as compared to the prior review period, or 13%. I will address coal and natural gas market conditions later in my testimony. The inventory levels maintained by PEC as shown on Exhibit No. 1 were adequate.

Q. Please describe the Company's coal procurement practices.

A. PEC continues to follow the same procurement practices that it has historically followed. These practices include determining and continuously monitoring coal consumption and inventory requirements; maintaining a list of qualified suppliers; conducting formal requests for proposals on a staggered basis; prudently combining market purchases and long term contracts; and monitoring supplier and rail performance. A summary of these practices is shown on Barkley Exhibit No. 2.

Q. Please describe the state of the coal market during the historical review period.

A. Barkley Exhibit No. 3, Page 1, presents market prices for CAPP, NAPP and ILB coal. During the current review period ended February 29, 2012, coal market prices in the CAPP region declined from approximately $70 per ton to approximately $55 per ton. Similarly, ILB market prices declined from approximately $53 per ton to approximately $40 per ton. This was primarily due to a mild winter, significant declines in the price of natural gas, mixed domestic economic indicators and less demand for coal exports based on international economic conditions. The reduced demand for coal resulting from these factors led to high levels of coal inventory by the end of the review period for PEC and many other domestic electric utilities.

The U.S. coal industry currently faces uncertainty associated with numerous federal regulatory initiatives including the Cross-State Air Pollution Rule, Mercury and Air Toxics Standards and the regulation of carbon emissions, coal ash, mine safety and water quality. While these initiatives are in various stages of judiciary review and development by the U.S. Environmental Protection Agency, utilities are preparing to reduce emissions. This uncertainty and increasing regulation has resulted in the announcement of coal-fired electric generating plant closures and retrofits that will likely reduce future coal demand and shift the location of supply sources.

While the market prices of coal decreased due to the factors I just described, coal providers continue to face rising costs related to fuel and increased safety requirements. Producers within the CAPP region continue to be affected by declining coal reserves which increases costs. The development of new coal supplies is negatively impacted by the difficulty of obtaining permits from the federal government due to water quality concerns associated with surface mining. As a result of this challenging environment, several major coal producers within the CAPP region have announced planned production cuts. These trends threaten the existence of certain coal mining companies and promote additional consolidation within the industry.

Finally, the development of coals used by PEC and other utilities, known as thermal or steam coal, has been negatively affected by the higher profit margins reaped from the sale of metallurgical coals used in steelmaking.

Q. If market prices have decreased, why has PEC's delivered cost of coal increased?

A. The current market price has little influence on the delivered cost of coal for the review period because almost all of the coal was received under contracts that were signed prior to the market decline that began in the fall of 2011. The contracts in effect during the prior review period had a lower average cost than those in effect during the current review period. I discuss PEC's strategy of staggered fixed price contracts later in my testimony. Finally, increases in transportation costs occurred independently of the recent coal price decline.

Q. What are PEC's expectations for coal market conditions during the forecasted period ending June 30, 2013 and beyond?

A. Exhibit No. 3, Page 1, indicates that the market price of coal is expected to increase during the remainder of 2012 and throughout 2013. The timing of such increase is subject to a myriad of factors that are difficult to predict including weather, the health of both U.S. and international economies, natural gas prices, judicial review of EPA proposals and the upcoming presidential election. PEC's cost per ton of coal consumed during the forecasted period is expected to remain relatively consistent with cost incurred during the review period, primarily due to PEC's policy of utilizing coal contracts generally ranging from one to three years in duration. As contracts expire, they will be replaced by contracts at current market values. Over time, the market price of coal is expected to increase and to exhibit volatility as it has done historically.

This is because many of the challenges faced by coal providers during the review period will persist. Morgan Stanley Research estimates that thermal coal production within CAPP will decline from approximately 200 million tons in 2002 to approximately 100 million tons in 2012 and then to approximately 25 million tons by 2020. As shown on Exhibit No. 3, coal prices for NAPP and ILB are also projected to increase. Importantly, these coals are expected to continue to be less expensive than CAPP coal. These coals present transportation and plant performance challenges for many companies such as PEC who have historically relied on a low to moderate sulfur coal from the CAPP region. As a result of the projected price relationship and the declining supply within CAPP, PEC is actively expanding its usage of coals from these regions.

Q. How does the Company select coal?

A. Evaluations of PEC's long-term and short-term coal needs are made from the standpoint of obtaining a reliable supply of coal at the lowest total cost. Items considered include coal price, coal quality, transportation cost, operating costs such as the limestone and ammonia needed to operate pollution control devices, maintenance costs, impacts on generating plant performance, emission allowance costs and any associated capital costs. PEC considers the reputation and ongoing financial viability of its suppliers and uses a wide variety of procurement options through its supplier bidding process in order to obtain the optimal coals for its generating fleet.

Q. How has PEC expanded its usage of coals with varying qualities and from non-traditional locations?

A. During the review period, PEC procured approximately 3 million tons of coal (30%) from non-traditional supply locations or that possessed characteristics that were not typical of PEC's historical coal supply. Characteristics of these coals include lower heat content, higher sulfur content, higher ash content and a lower melting point, known as ash softening temperature, than PEC's traditional CAPP supply. PEC will continue to evaluate coals from these locations and CAPP coal with atypical characteristics.

Q. What steps were taken in order to facilitate these new sources of coal supply?

A. The process for evaluating non-traditional coals involves several steps including computer based modeling, short-term demonstrations and controlled tests lasting for a month or more. To date, PEC has invested approximately $68 million to facilitate the handling and consumption of these coals. These investments were necessitated by the properties of the new coals. Expenditures were primarily directed to combustion improvements and mitigating the formation and collection of residue within boilers caused by the lower ash softening temperatures and higher ash content of these coals, and mitigation of chemical compounds produced by the combustion of higher sulfur coals that can cause corrosion of components. Also, coal handling improvements were made in order to mitigate issues resulting from the increased fineness of certain coals.

Q. Did customer savings result during the review period and do you expect them to continue?

A. Yes, coals from ILB and NAPP as well as lower quality coals from within CAPP were purchased at prices that were lower than PEC's traditional supply. Further, the price per ton for coal from NAPP and ILB are forecasted to remain less expensive than CAPP coal as shown on Page 1 of Barkley Exhibit No. 3. PEC has secured a significant amount of coal from these regions to be delivered during the forecasted period and will continue to do so if the economics remain favorable. Further, PEC's preparation for and selection of these coals created regional market competition that would not have existed otherwise.

Q. Please describe PEC's policies associated with long term coal contracting.

A. PEC hedges its coal costs by entering into long term contracts at fixed prices for a significant portion of its projected coal needs. Any additional coal requirements are purchased on the spot market as needed to maintain inventories. Long-term contracts enhance the reliability of coal supply and reduce price volatility. PEC staggers contract expiration dates so that a portion of the contracts expire each year and is replaced with new contracts of corresponding duration, similar to the investing strategy known as dollar cost averaging. This structure of tiered contracts provides a reasonable degree of cost stability and allows the Company to respond appropriately to market trends.

Q. How is coal transported to PEC?

A. Coal has been traditionally transported by rail using either the CSX railway or the NS railway. PEC receives a limited amount of coal by truck at Asheville and has received foreign coal by barge at the Sutton Plant located near Wilmington, NC. Receipt points for coal delivered by rail are generally in the CAPP region, but can include coal delivered to the port at Charleston, SC. To minimize transportation costs, PEC negotiates the most advantageous rates reasonably possible and participates, through a consortium of shippers, in proceedings before the Federal Surface Transportation Board. The acquisition of coals from NAPP and ILB required new modes of transportation for PEC. PEC's strategy for transporting these coals is to deliver them using river barges to locations in West Virginia and then using rail from those locations to PEC's plants. PEC's use of water, water to rail, and trucking demonstrates its continuing commitment to diversification of coal transportation.

Q. Do you currently expect major changes to coal transportation costs during the forecasted period?

A. No.

Q. Please describe your procurement practices for natural gas.

A. PEC follows a process that is very similar to that discussed earlier for coal. Production costing models are used to project PEC's future natural gas requirements. Based on the projections, requests for proposals are made, bids received, and contracts based on monthly and daily price indices are established to cover the large majority of the projected requirement for the coming year. Declining percentages of firm needs are obtained for periods of up to four years. Long term contracts are established and maintained for gas transportation. On a short term basis, additional purchases on the spot market are made as needed to manage the Company's natural gas requirements.

Q. Please describe gas cost trends during the review period.

A. As shown on Barkley Exhibit No. 3, Page 2, natural gas market prices remained at low levels, approximating an average cost of $3.70 per mmbtu during the review period. Toward the end of the review period, natural gas prices fell below $2.50 per mmbtu which had not occurred since 2002. A major contributor to these low prices was the very mild winter, with U.S. degree days more than 15% below normal. Despite the low market prices and weak demand, natural gas production increased by 8% in 2011, the largest annual increase in history. This was attributable to increases in shale gas production and to the supply of natural gas that was obtained as a result of drilling efforts targeting oil and other liquid products. The proliferation of shale gas development continued with shale gas approaching 25% of U.S. supply during 2011. Shale gas is expected to grow to approximately 50% of domestic supply by 2030. As discussed in my testimony in previous years, the cost of obtaining natural gas from shale deposits through horizontal drilling and hydraulic fracturing which began to be developed in large quantities over the past few years has dramatically added to U.S. natural gas production and reserve levels.

The impact of weak demand and robust supply has resulted in record levels of natural gas inventory. The amount of natural gas stored in the U.S. at February 29, 2012 exceeded the five-year average for February month end by approximately 50%.

Q. Please describe PEC's expectations for the natural gas market for the forecasted period.

A. The market price of natural gas is projected to approximate $3 per mmbtu during the forecasted period. Inventory levels are expected to remain high at least until the

2012 – 2013 winter heating season arrives. Some suppliers have announced planned supply cuts as a result of the depressed market price. Over time, natural gas prices are expected to increase as the inventory is reduced by a combination of supply reduction, increased usage and a return to normal weather. Additionally, volatility is expected to persist in response to issues including weather, global economic conditions, legislative initiatives that could impact shale gas production, geopolitical turmoil and natural disasters.

Q Please discuss PEC's historical hedging practices for natural gas.

A. PEC began executing fixed price contracts for a portion of its natural gas requirements in 2005 in response to increased natural gas consumption and the volatility of natural gas market prices. Hedging via financial instruments was subsequently added. PEC's targeted natural gas price assurance target is 50% for the upcoming twelve months, with declining percentages for the succeeding two years. Actual hedged percentages can vary from targeted percentages based upon variances in natural gas consumption which are driven by weather, market prices, generating plant performance and other factors. For this review period, approximately 49% of PEC's actual consumption was hedged. Customers participated fully in the market price decline for the 51% of PEC's natural gas consumption that was not hedged.

Q. Did PEC adjust its hedging approach in light of the shale gas proliferation?

A. Yes, PEC began hedging at the lower end of its established hedging targets and reduced its hedging time horizon to the previously-referenced rolling 36-month period. The targets for the second and third years of PEC's hedging program are 30% and 10% respectively.

Q. Does PEC plan to continue hedging for natural gas?

A. Yes. A cessation of hedging would expose customers to price risk and volatility. PEC's annual natural gas usage is expected to increase from current levels and will therefore be a larger component of PEC's overall fuel mix. In the summer of 2011, PEC placed into commercial service an additional combined cycle unit at its Richmond County location. PEC also plans to add new combined cycle units at Wayne County by January 2013 and at the Sutton facility by January 2014. These new facilities will add approximately 2150 megawatts of combined cycle generation. PEC's forecasted natural gas consumption in 2014 is approximately twice the amount consumed during the review period. Hedges for future periods are available at historically low levels and the current low-priced environment remains prone to volatility from numerous factors as previously discussed. Mitigation of volatility in PEC's natural gas costs and fuel cost rates continues to be an important goal. PEC believes that a start and stop approach to managing price risk is inappropriate for any of its fuel sources and that an approach applied consistently and monitored continuously over time is the best way to reduce fuel cost volatility.

Q. Does PEC purchase power and how are these costs recorded?

A. Yes. As explained by PEC witness Roberts, PEC continuously evaluates purchasing power if it can be reliably procured and delivered at a price that is less than the variable cost of PEC's generation. In accordance with S.C. Code Ann. §

58-27-865(A), PEC recovers from its South Carolina retail customers an amount that is the lower of the purchase price or PEC's avoided variable cost for generating an equivalent amount of power for its economy purchases. PEC also purchases power from certain suppliers that are treated as firm generation capacity purchases. In accordance with the statute, all amounts paid to these suppliers are recorded as recoverable fuel costs with the exception of capacity charges.

Q. Please explain Barkley Exhibit No. 4

A. Barkley Exhibit No. 4 is a summary of PEC's actual system fuel cost experienced during the period March 2011 through February 2012. Total system fuel costs were $1,501,821,640.

Q. How did the fuel revenue billings compare to the actual fuel costs incurred during the review period March 2011 through February 2012?

A. Barkley Exhibit No. 5 is a monthly comparison of fuel revenues billed to South Carolina retail customers to the actual jurisdictional fuel costs attributable to those sales. PEC's fuel recovery status changed from an under-recovery of $12.2 million at February 28, 2011 to an over-recovery of $4.3 million at February 29, 2012.

Q. Please explain Barkley Exhibit No. 6.

A. Barkley Exhibit No. 6 presents PEC's recommended fuel rate of 2.707 ¢/kWh for the 12-month period July 2012 through June 2013, consisting of a component for the recovery of projected fuel expense of 2.798 ¢/kWh and a component to return the projected over-recovery at June 30, 2012 of .091 ¢/kWh. The projected over-recovery at June 30, 2012 is $5.8 million as shown on Barkley Exhibit No. 7.

The fuel forecast supporting the projected fuel cost was generated by an hourly dispatch model that considers the latest forecasted fuel prices, outages at the generating plants based on planned maintenance and refueling schedules, forced outages based on historical trends, generating unit performance parameters and expected market conditions associated with power purchase and off-system sales opportunities.

Q. Please explain Barkley Exhibit No. 7.

A. Barkley Exhibit No. 7 provides projected costs and revenues, by month, for the period March 2012 through June 2013. The exhibit continues the use of the currently approved fuel factor of 3.041 ¢/kWh through June 2012 and includes PEC's recommended factor of 2.707 ¢/kWh for the period July 2012 through June 2013. PEC's proposed fuel factor practically eliminates the deferred fuel balance as of June 30, 2013.

Q. Please provide a status update of environmental cost collection and explain how these costs have been treated in this filing.

A. PEC recovers the costs of ammonia, limestone and emission allowances through an environmental cost rider that is adjusted annually. Environmental costs allocated to the SC retail jurisdiction during the review period were approximately $2.4 million as shown on Barkley Exhibit No. 8. The overcollected deferred account balance was $367,387 at February 29, 2012.

Q. Have you provided a forecast of environmental costs and what is your expectation for the deferred account status at the conclusion of the forecasted period?

A. Yes, Barkley Exhibit No. 9 presents PEC's estimated environmental costs for the period from July 2012 through June 2013 of $23,890,872. The SC retail portion is forecasted to be approximately $2.8 million. PEC currently estimates that its deferred environmental cost balance will be an overcollection of $479,595 at June 30, 2012 as shown on Barkley Exhibit No. 10 and that this deferred account balance will be practically eliminated by June 30, 2013.

Q. How did PEC allocate environmental costs?

A. Environmental costs were allocated to Residential, General Service (non-demand), General Service (demand) and Lighting rate classes based upon the coincident peak experienced during the review period. This allocation is shown on Barkley Exhibit No. 9. Rates were designed based on costs allocated to the respective rate classes and the projected energy consumption for the residential, general service (non-demand) and lighting schedules. The rate for the general service (demand) class was based on projected annual demand. All allocations were consistent with the methodology approved by the PSCSC in PEC's 2007 fuel review proceeding, Order No. 2007-440 issued July 20, 2007. This methodology has been consistently used in each fuel case since the issuance of this Order.

Q. Have you presented PEC's proposed fuel factors?

A. Yes. Barkley Exhibit No. 11 presents proposed fuel rates including an amount added to account for the 5% discount provided to residential customers under PEC's SC Residential Service Energy Conservation Discount Rider RECD-2B.

Q. Why does PEC propose inclusion of the effects of Rider RECD-2B?

A. Failure to recognize the impact of the 5% discount would result in an overstatement of PEC's fuel revenues and an understatement of amounts owed to PEC by its customers. PEC should not reflect fuel revenue collections for 100% of its fuel billings while simultaneously providing a 5% discount on the total bill as required by Rider RECD-2B. As shown on Barkley Exhibit No. 12, this discount impacts approximately 16% of PEC's SC residential sales.

Q. Has the impact of the 5% discount been recognized in prior fuel review proceedings?

A. Yes. PEC's request in this proceeding is consistent with the PSCSC's Orders issued in all fuel proceedings since 2009.

Q. Were PEC's fuel and environmental costs prudently incurred during the review period?

A. Yes. PEC's fuel and environmental costs were prudently incurred and accurately recorded and are fully recoverable pursuant to South Carolina law. As discussed by PEC witness Roberts, PEC prudently operated its generation resources during the period under review in order to minimize its fuel costs and purchased power when doing so was cost effective.

Q. What are the customer impacts of PEC's proposed rate changes?

A. The impact of the proposed fuel rate decrease for an average residential customer using 1000 kWh per month is a reduction of $3.52, or 3.4%. Impacts for commercial and industrial customers vary by customer, but approximate 4% and 5%, respectively.

Q. **How does PEC propose to address the fuel-related savings that will result from its proposed merger with Duke Energy?**

A. Upon receipt of all necessary approvals and closure of the merger, PEC will propose a reduction in its fuel rates to pass along the forecasted merger-related fuel cost savings.

Q. **Does that complete your testimony?**

A. Yes, it does.

**PROGRESS ENERGY CAROLINAS, INC.
FUEL CONSUMED, PURCHASED AND INVENTORIED
FOR THE TWELVE MONTHS ENDED FEBRUARY 29, 2012
ALL AMOUNTS GROSS OF NCEMPA OWNERSHIP**

COAL			Tons	$/Ton
	Consumed		9,264,255	$89.19
	Coal Purchased		10,191,243	$63.03
	Freight Purchased		10,191,243	$28.08
	Total Purchased		10,191,243	$91.11
	$/mmbtu consumed	$3.68		
OIL			Gallons	$/Gallon
	Consumed		10,705,433	$2.59
	Purchased		13,205,076	$3.16
	$/mmbtu consumed	$18.72		
NATURAL GAS			mmbtu	$/mmbtu
	Consumed		70,197,871	$5.62
	Purchased		70,214,751	$5.62

INVENTORIES AS OF FEBRUARY 28/29

	2011 Units	2011 $/Unit	2012 Units	2012 $/Unit
Coal (tons)	1,528,790	$86.96	2,455,778	$95.77
Oil (gallons)	25,779,095	$1.89	27,748,653	$2.21
Natural Gas (mmbtu)	136,841	$4.45	153,721	$3.01

Progress Energy Carolina's Coal Procurement Practices

1. **Estimate Fuel Requirements.** Fuel requirements are estimated annually using a long-term forecasting simulation model and monthly using a short-term simulation model. Both simulation models include load forecasts, system planning and capacity factors for all generating plants.

2. **Establish Inventory Requirements.** PEC uses historic inventory patterns to determine current inventory levels. Currently, PEC targets coal inventories between 45 to 55 days, depending on the season of the year.

3. **Monitor Ongoing Fuel Requirements.** On an ongoing basis, there is a review and evaluation of current inventory levels, supplier performance and forecasted short-term requirements and commitments to determine additional fuel requirements.

4. **Maintain Master Bidder List.** A list of bidders is maintained throughout the year. All bidders on this list receive coal solicitations from PEC. If a supplier's bid is deemed competitive, supplier capabilities are evaluated including current performance, reserves, coal quality, railroad origination, financial condition of supplier and loading capabilities.

5. **Bid Requests.** Formal solicitations are sent to all suppliers on the Master Bidder List for spot and/or longer term coal as needed. PEC seeks staggered expiration terms to reduce the impact of market volatility on customer rates.

Progress Energy Carolina's Coal Procurement Practices

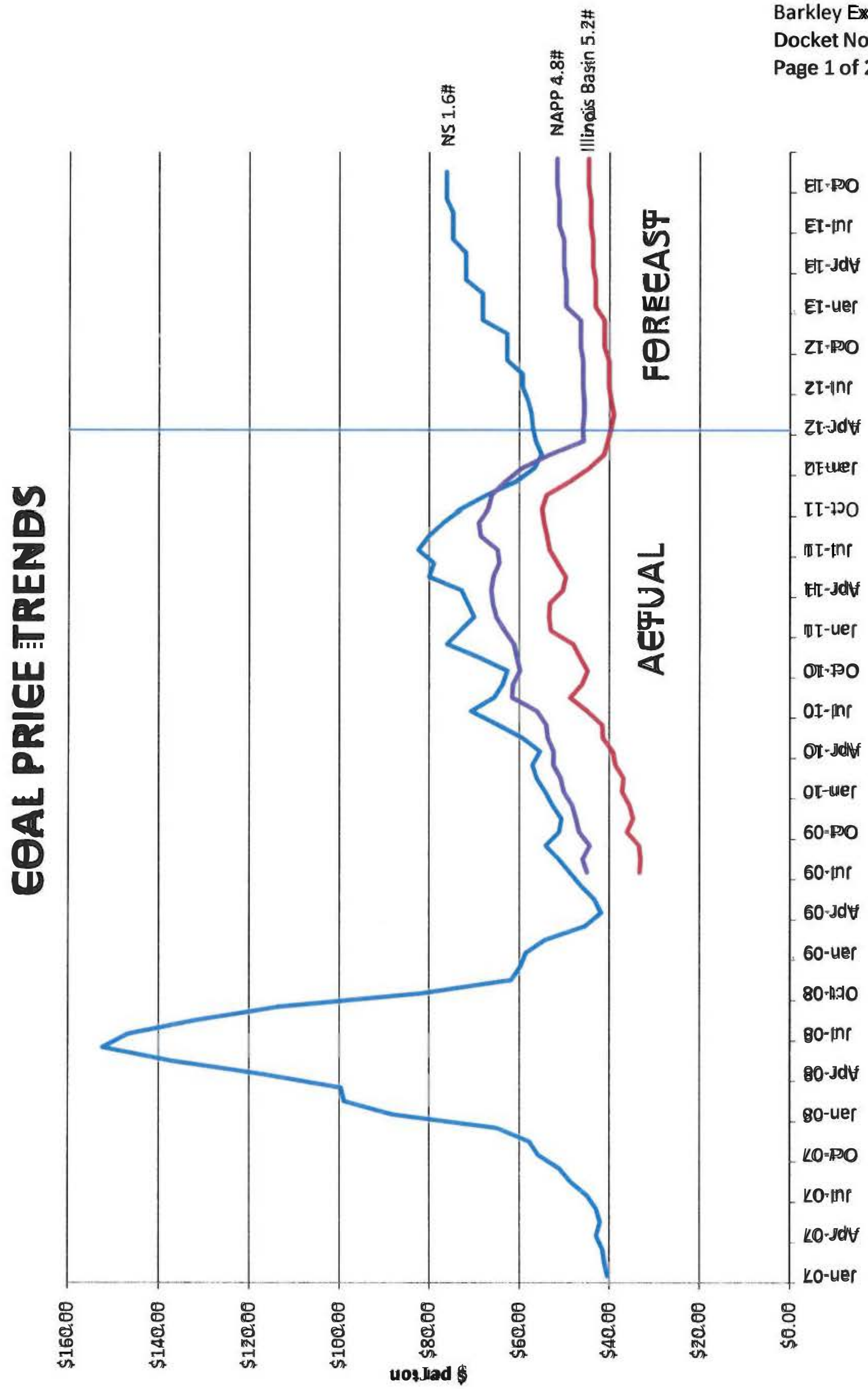
6. **Bid Evaluation**. Contracts are awarded after a thorough evaluation process including an economic evaluation, financial and credit review of the supplier, performance evaluation, coal quality conformance with plant requirements, supplier quality controls, test burns (if necessary) and compliance with federal environmental regulations.

7. **Spot Purchases**. To supplement PEC's coal supply, short-term spot offers are solicited as needed and purchases made in accordance to needs. These purchases may be limited to a single train. Unsolicited offers are also considered as they are received.

8. **Monitoring of Purchases**. Purchases are administered, monitored and expedited as needed to ensure compliance with contractual terms.

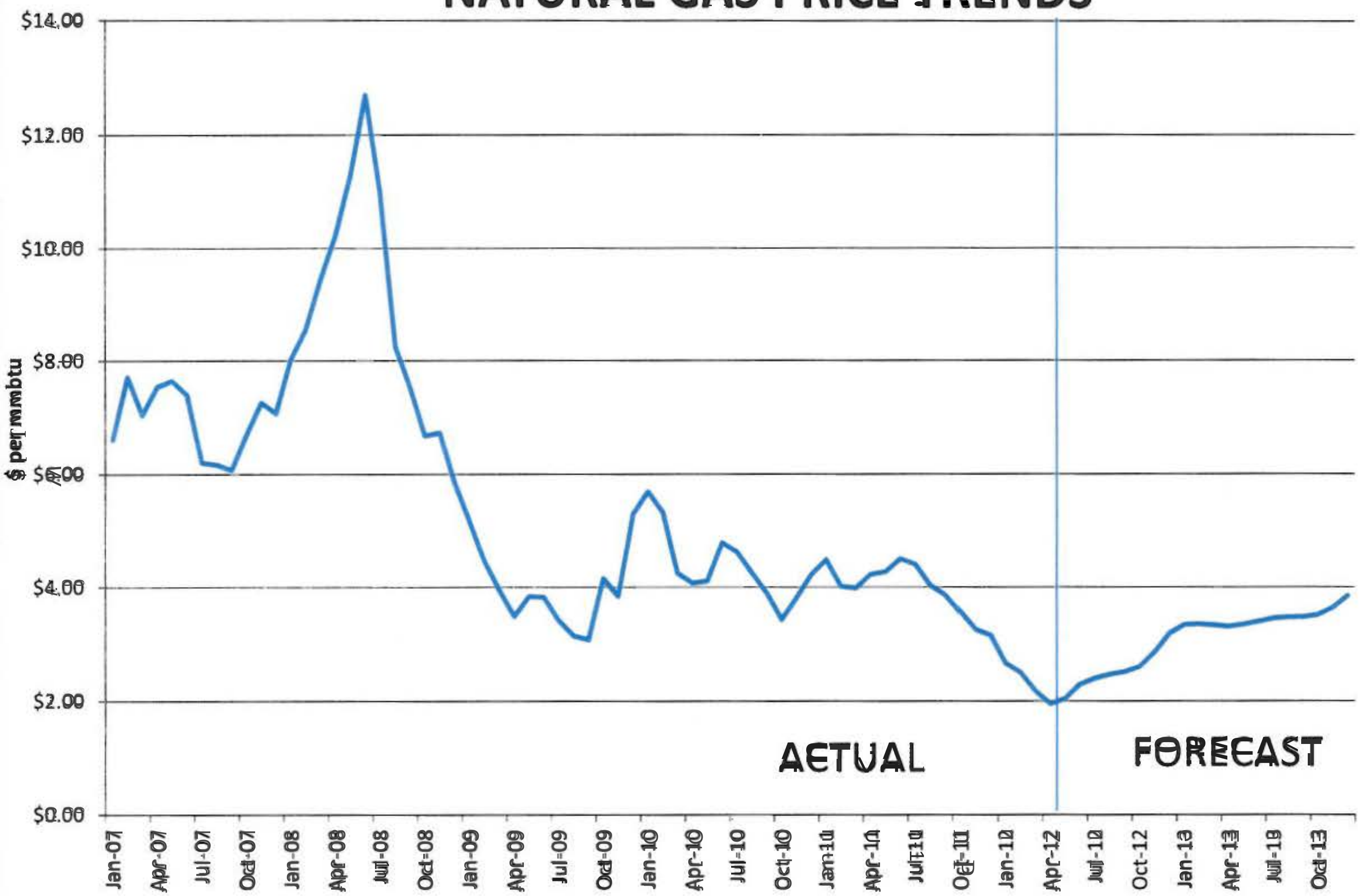
9. **Quality Control.** The Company requires suppliers to sample, analyze and weigh all coal shipped under the agreements using independent third party labs (ASTM Standards) and certified scales. Three to four samples are typical with one sample being a referee sample should a dispute arise. Sample analyses are used for contractual quality pricing adjustments. Weighing is done at the mine using certified scales and, if no scales are certified at the mine, certified railroad scales are used.

Barkley Exhibit No. 3
Docket No. 2012-1-E



Barkley Exhibit No. 3
Docket No. 2012-1-E
Page 2 of 2

NATURAL GAS PRICE TRENDS



Actual - NYMEX
Forecast - NYMEX Prices as of 04/30/2012
Henry Hub Prices

PROGRESS ENERGY CAROLINAS, INC.

SYSTEM FUEL COST

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2012-1-E
TWELVE MONTHS ENDED FEBRUARY 2012

Line		Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11
(1)	Coal	$66,729,426.17	$61,009,529.89	$54,721,865.10	$83,283,280.59	$88,993,694.52	$86,105,858.41
(2)	Oil - Steam	1,290,412.69	590,998.99	1,136,043.48	1,267,981.07	1,325,360.32	1,004,846.08
(3)	Oil - Turbine	199,174.46	556,331.95	943,955.62	2,013,089.14	115,597.08	394,994.03
(4)	Gas - Turbine	19,552,602.54	17,061,964.78	34,118,531.87	42,237,385.19	50,069,844.97	43,925,065.99
(5)	**Total Fossil**	87,771,615.86	79,218,825.61	90,920,396.07	128,801,735.99	140,504,496.89	131,430,764.51
(6)	**Nuclear Fuel**	11,616,900.46	12,074,026.67	14,317,849.61	14,246,941.69	14,124,854.45	14,037,380.35
(7)	**Purchased Power**	15,743,093.74	16,139,045.65	20,390,369.60	23,177,751.35	30,243,513.48	27,151,264.71
(8)	**Off-System Sales**	(6,281,285.35)	(4,626,088.21)	(5,986,196.32)	(12,222,767.53)	(14,499,494.24)	(11,858,773.60)
(9)	**Total Fuel Costs**	$108,850,324.71	$102,805,809.72	$119,642,418.96	$154,003,661.50	$170,373,370.58	$160,760,635.97

Line		Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Twelve Months Ended Feb-12
(10)	Coal	$62,778,747.16	$39,730,455.86	$55,919,934.93	$52,049,479.08	$67,577,581.17	$66,149,132.53	$785,048,985.41
(11)	Oil - Steam	1,483,384.90	1,130,497.22	1,803,261.08	1,246,136.43	1,609,747.41	1,332,268.56	$15,220,938.23
(12)	Oil - Turbine	158,990.06	55,487.66	94,090.66	781,104.07	4,331,441.54	2,082,245.33	$11,726,501.60
(13)	Gas - Turbine	31,030,710.10	28,253,116.83	31,653,366.87	29,703,277.17	30,357,690.73	35,167,258.55	$393,130,815.59
(14)	**Total Fossil**	95,451,832.22	69,169,557.57	89,470,653.54	83,779,996.75	103,876,460.85	104,730,904.97	),205,127,240.83
(15)	**Nuclear Fuel**	13,250,855.99	14,218,486.49	10,722,452.89	13,847,353.91	12,792,135.64	9,377,612.97	$154,626,851.12
(16)	**Purchased Power**	22,541,072.09	13,630,509.23	19,121,523.21	15,919,374.78	15,325,359.18	13,543,938.48	$232,926,815.50
(17)	**Off-System Sales**	(8,026,791.13)	(4,912,320.20)	(6,513,430.28)	(5,953,031.06)	(4,691,993.70)	(5,287,095.53)	(90,859,267.15)
(18)	**Total Fuel Costs**	$123,216,969.17	$92,106,233.09	$112,801,199.36	$107,593,694.38	$127,301,961.97	$122,365,360.89	$1,501,821,640.30

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Actual Fuel Revenues and Expenses
SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2012-1-E
TWELVE MONTHS ENDED FEBRUARY 2012

Line		Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11
(1)	Total Fuel Costs [$]	$108,850,324.71	$102,805,809.72	$119,642,418.96	$154,003,661.50	$170,373,370.58	$160,760,635.97
(2)	Actual SC Retail Sales [KWH]	437,672,999	460,798,163	498,654,087	555,313,219	585,769,521	637,617,833
(3)	Total System KWH Sales (Exc. Power Agency)	3,994,404,821	3,769,076,894	3,913,731,740	4,946,731,584	5,008,889,151	5,366,065,721
(4)	SC Allocation Factor	0.1096	0.1223	0.1274	0.1123	0.1169	0.1188
(5)	Revenue Required [$]	$11,929,996	$12,573,151	$15,242,444	$17,294,611	$19,916,647	$19,098,364
(6)	Revenue Billed [$]	$11,918,068	$12,546,893	$13,576,010	$15,177,542	$17,812,314	$19,390,563
(7)	Over (Under) Recovery [$]	($11,928)	($26,258)	($1,666,434)	($2,117,069)	($2,104,333)	$292,199
(8)	Accounting Adjustments [$]	$1,075	$0	$0	$1,749,966	$0	$0
(9)	Cumulative Over (Under) Recovery [$]	($12,180,005)	($12,206,262)	($13,872,697)	($14,239,800)	($16,344,132)	($16,051,933)

Line		Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Twelve Months Ended Feb-12
(10)	Total Fuel Costs [$]	$123,216,969.17	$92,106,233.09	$112,801,199.36	$107,593,694.38	$127,301,961.97	$122,365,360.89	$1,501,821,640.30
(11)	Actual SC Retail Sales [KWH]	516,594,988	518,257,546	446,482,874	440,799,340	553,900,218	491,933,620	6,143,794,408
(12)	Total System KWH Sales (Exc. Power Agency)	4,628,891,901	4,035,047,820	3,814,250,787	4,146,804,450	4,561,800,061	4,235,338,555	52,421,033,485
(13)	SC Allocation Factor	0.1116	0.1284	0.1171	0.1063	0.1214	0.1161	
(14)	Revenue Required [$]	$13,751,014	$11,826,440	$13,209,020	$11,437,210	$15,454,458	$14,206,618	$175,939,973
(15)	Revenue Billed [$]	$15,709,029	$15,759,029	$13,579,052	$13,406,939	$16,846,957	$14,962,554	$180,684,951
(16)	Over (Under) Recovery [$]	$1,958,015	$3,932,589	$370,032	$1,969,729	$1,392,499	$755,936	$4,744,978
(17)	Accounting Adjustments [$]	$10,000,000	$0	$0	$0	$0	$2,137	$11,753,178
(18)	Cumulative Over (Under) Recovery [$]	($4,093,918)	($161,329)	$208,703	$2,178,432	$3,570,932	$4,329,004	

Barkley Exhibit No. 5
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2012-1-E
CALCULATION OF BASE FUEL COMPONENT
For the Year Ending June 30, 2013

1. Projected Fuel Expense from July 2012 through June 2013

Cost of Fuel	$1,518,821,114	
System Sales	54,285,666	Mwhs
Average Cost Per kWh	2.798	cents / kWh

2. Revenue Difference To be Collected from July 2012 through June 2013

(Over)/Under-Recovery at June 30, 2012	($5,796,927)	
Projected S.C. Retail Sales	6,391,904	Mwhs
Average Cost Per kWh	(0.091)	cents / kWh

3. Base Fuel Cost Per KWH - Projected Period

Average Fuel Cost	2.798	cents / kWh
Revenue Difference	(0.091)	cents / kWh
Base Fuel Component	2.707	cents / kWh

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Estimated Fuel Revenues and Expenses
SOUTH CAROLINA RETAIL FUEL CASE • Docket No. 2012-1-E

Line		Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
(1)	Total Fuel Costs [$]	$121,253,668.56	$107,220,080.61	$114,128,386.07	$134,572,183.92	$152,757,910.45	$155,709,484.28	$119,993,840.55	$105,442,947.37
(2)	SC Retail Sales [KWH]	396,639,808	514,387,618	455,676,246	548,325,595	591,677,843	615,271,712	582,537,370	494,720,032
(3)	Total System KWH Sales (Exc. Power Agency	3,840,900,637	3,831,660,908	3,848,268,559	4,515,593,130	5,065,489,403	5,146,395,741	4,760,589,764	4,070,031,589
(4)	SC Allocation Factor	0.10330	0.13420	0.12004	0.12004	0.11775	0.11775	0.11775	0.11775
(5)	Revenue Required [$]	$12,525,503.96	$14,388,934.82	$13,699,971.46	$16,154,044.96	$17,987,243.96	$18,334,791.77	$14,129,274.72	$12,415,907.05
(6)	Revenue Billed [$]	$12,063,157.01	$15,641,525.52	$13,857,114.65	$16,674,581.36	$16,016,719.22	$16,655,405.24	$15,769,286.61	$13,392,071.26
(7)	Over (Under) Recovery [$]	($462,346.95)	$1,252,590.70	$157,143.18	$520,536.40	($1,970,524.74)	($1,679,386.53)	$1,640,011.89	$976,164.21
(8)	Accounting Adjustments [$]								
(9)	Cumulative Over (Under) Recovery [$]	$3,866,657	$5,119,248	$5,276,391	$5,796,927	$3,826,403	$2,147,016	$3,787,028	$4,763,192

Line		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
(10)	Total Fuel Costs [$]	$102,000,204.13	$138,131,533.48	$149,875,012.60	$123,629,901.49	$119,356,311.77	$101,671,587.26	$108,916,537.17	$141,335,842.97
(11)	SC Retail Sales [KWH]	447,202,665	507,538,839	613,692,815	553,121,816	503,655,564	476,590,329	456,630,056	549,265,346
(12)	Total System KWH Sales (Exc. Power Agency	3,826,676,683	4,482,245,657	5,195,581,291	4,760,113,173	4,363,389,008	4,011,765,543	3,909,938,487	4,693,449,249
(13)	SC Allocation Factor	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775
(14)	Revenue Required [$]	$12,010,524.04	$16,264,988.07	$17,647,182.73	$14,557,420.90	$14,054,205.71	$11,971,829.40	$12,824,922.25	$16,642,295.51
(15)	Revenue Billed [$]	$12,105,776.15	$13,739,076.36	$16,612,664.50	$14,973,007.55	$13,633,956.13	$12,901,300.20	$12,360,975.62	$14,868,612.92
(16)	Over (Under) Recovery [$]	$95,252.11	($2,525,911.71)	($1,035,118.23)	$415,586.65	($420,249.58)	$929,470.80	($463,946.63)	($1,773,682.59)
(17)	Accounting Adjustments [$]								
(18)	Cumulative Over (Under) Recovery [$]	$4,858,444.30	$2,332,532.59	$1,297,414.36	$1,713,001.01	$1,292,751.43	$2,222,222.23	$1,758,275.60	($15,406.99)

Barkley Exhibit No. 7
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.

SYSTEM ENVIRONMENTAL COST

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2012-1-E
TWELVE MONTHS ENDED FEBRUARY 2012

Line		Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11
(1)	Emission Allowances	$368,919.24	$256,227.38	$234,450.30	$449,283.51	$463,712.48	$421,585.25
(2)	Ammonia	583,061.13	572,402.88	592,802.81	775,053.62	911,170.93	804,414.64
(3)	Limestone	572,662.46	589,673.14	617,698.44	829,799.58	1,064,994.36	958,179.93
(4)	Total Environmental Costs	1,524,642.83	1,418,303.40	1,444,951.55	2,054,136.71	2,439,877.77	2,184,179.82
(5)	Total Off-System Sales [$]	(3,007.55)	(4,419.11)	(17,188.36)	(32,429.85)	(30,094.14)	(16,536.56)
(6)	Total Environmental Expense	$1,521,635.28	$1,413,884.29	$1,427,763.19	$2,021,706.86	$2,409,783.63	$2,167,643.26
(7)	SC Retail Sales (kWh)	437,672,999	460,798,163	498,654,087	555,313,219	585,769,521	637,617,833
(8)	Total System Sales (kWh) (Exclude Power Agency)	3,994,404,821	3,769,076,894	3,913,731,740	4,946,731,584	5,008,889,151	5,366,065,721
(9)	SC Allocation Factor	0.1096	0.1223	0.1274	0.1123	0.1169	0.1188
(10)	SC Share of Total Environmental Costs	$166,771.23	$172,918.05	$181,897.03	$227,037.68	$281,703.71	$257,516.02
(11)	Amount Billed to SC Customers [$]	158,922.49	148,268.42	146,065.48	188,074.27	278,236.96	288,935.60
(12)	Over (Under) Recovery [$]	($7,848.74)	($24,649.63)	($35,831.55)	($38,963.41)	($3,466.75)	$31,419.58
(13)	Accounting Adjustments [$]	(33.63)	-	-	33.63	-	-
(14)	Cumulative Over (Under) Recovery [$]	$91,498.11	$66,848.48	$31,016.93	($7,912.85)	($11,379.59)	$20,039.99

Line		Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Twelve Months Ended Feb-12
(15)	Emission Allowances	$274,751.79	$141,949.61	$232,336.78	$141,199.10	$116,025.80	$120,472.09	$3,220,913.33
(16)	Ammonia	687,867.34	390,476.20	456,048.90	610,628.78	712,366.41	693,979.14	7,790,272.78
(17)	Limestone	879,586.53	449,212.54	656,019.09	732,891.08	846,942.17	1,267,495.71	9,465,155.03
(18)	Total Environmental Costs	$1,842,205.66	$981,638.35	$1,344,404.77	$1,484,718.96	$1,675,334.38	$2,081,946.94	$20,476,341.14
(19)	Total Off-System Sales [$]	(7,340.85)	(474.62)	(4,311.88)	(527.07)	(5,061.53)	(17,042.55)	(138,434.07)
(20)	Total Environmental Expense	$1,834,864.81	$981,163.73	$1,340,092.89	$1,484,191.89	$1,670,272.85	$2,064,904.39	$20,337,907.07
(21)	SC Retail Sales (kWh)	516,594,988	518,257,546	446,482,874	440,799,340	553,900,218	491,933,620	6,143,794,408
(22)	Total System Sales (kWh) (Exclude Power Agency)	4,628,891,901	4,035,047,820	3,814,250,787	4,146,804,450	4,561,800,061	4,235,338,555	52,421,033,485
(23)	SC Allocation Factor	0.1116	0.1284	0.1171	0.1063	0.1214	0.1161	
(24)	SC Share of Total Environmental Costs	$204,770.91	$125,981.42	$156,924.88	$157,769.60	$202,771.12	$239,735.40	$2,375,797.05
(25)	Amount Billed to SC Customers [$]	257,996.06	216,437.20	213,940.53	235,543.67	265,981.29	245,401.32	2,643,803.29
(26)	Over (Under) Recovery [$]	$53,225.15	$90,455.78	$57,015.65	$77,774.07	$63,210.17	$5,665.92	$268,006.24
(27)	Accounting Adjustments [$]	-	-	-	-	-	-	-
(28)	Cumulative Over (Under) Recovery [$]	$73,265.14	$163,720.91	$220,736.57	$298,510.64	$361,720.80	$367,386.72	

Barkley Exhibit No. 9
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2012-1-E
CALCULATION OF ENVIRONMENTAL FUEL COMPONENT
For the Year Ending June 30, 2013

Line	Class	Allocation Factor	Share of Projected Costs	Share of (Over)/Under-Recovery at June 30, 2012	Projected July 12 to June 13 SC Retail Sales (kWh)	Projected Demand Billing units (kW)	Projected Average Environmental Fuel Cost	(Over)/Under-Recovered Average Environmental Fuel Cost	Total Environmental Fuel Cost Component
(1)	Residential	44.83%	$1,261,154	($215,005)	2,085,338,156		0.060 ¢/kWh	(0.010) ¢/kWh	0.050 ¢/kWh
(2)	General Service (non demand)	6.21%	$174,711	($29,785)	291,202,737		0.060 ¢/kWh	(0.010) ¢/kWh	0.050 ¢/kWh
(3)	General Service (demand)	48.96%	$1,377,285	($234,803)	3,925,068,918	9,177,626	15 ¢/kW [1]	(3) ¢/kW [1]	12 ¢/kW
(4)	Lighting	0.00%	$0	$0	90,294,576		0.000	0.000	0.000
(5)	Total	100.00%	$2,813,150	($479,594)	6,391,904,387	9,177,626			

SC Environmental Cost Projection

(6)	Projected SC Retail Sales from July 12 to June 13	6,391,904,387
(7)	Projected Total System Sales from July 12 to June 13	54,285,665,588
(8)	Allocation percentage to SC	0.11775
(9)	Projected Environmental Costs July 11 to June 12	$23,890,872
(10)	SC Allocation of Projected Costs	$2,813,150

[1] Rate is based on the Demand Billing Units

Barkley Exhibit No. 9
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Estimated Environmental Fuel Revenues and Expenses

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2012-1-E

Line		Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12
(1)	Estimated SO2 Expense [$]	91,808	87,265	55,862	92,088	112,831	126,117	71,304	44,891
(2)	Estimated Ammonia & Limestone Expense [$]	1,629,892	1,294,552	1,574,451	1,898,254	2,100,316	2,178,595	1,738,702	1,505,291
(3)	Estimated NOx Expense [$]	43,137	39,919	55,648	72,990	86,720	92,587	57,396	22,283
(4)	Estimated Off-System Sales [$]	(26,640)	(40,366)	(48,543)	(45,487)	(47,064)	(60,032)	(26,946)	(28,673)
(5)	Estimated Total Environmental Expense [$]	1,738,196	1,381,370	1,637,418	2,017,845	2,252,803	2,337,267	1,840,457	1,543,792
(6)	Estimated SC Allocation Factor of Total Expense	0.10330	0.13420	0.12004	0.12004	0.11775	0.11775	0.11775	0.11775
(7)	SC Share of Total Environmental Expense [$]	179,556	185,380	196,556	242,222	265,268	275,213	216,714	181,782
(8)	Residential kWh	154,091,485	130,634,823	116,595,870	174,869,401	217,686,148	204,345,196	174,926,511	126,747,622
(9)	Residential Recovery Rate	0.00065	0.00065	0.00065	0.00065	0.0005	0.0005	0.0005	0.0005
(10)	Residential Recovery [$]	99,371	84,199	75,787	113,665	108,843	102,173	87,463	63,374
(11)	General Service (Non-Demand) kWh	20,499,649	20,913,164	19,893,349	25,369,958	30,081,673	30,612,712	28,470,869	23,360,143
(12)	General Service (Non-Demand) Recovery Rate	0.00061	0.00061	0.00061	0.00061	0.00050	0.00050	0.00050	0.00050
(13)	General Service (Non-Demand) Recovery [$]	12,505	12,757	12,135	15,476	15,041	15,306	14,235	11,680
(14)	General Service Demand kW	608,751	606,592	643,800	863,223	765,694	695,472	839,159	666,672
(15)	General Service Recovery Rate	0.18	0.18	0.18	0.18	0.12	0.12	0.12	0.12
(16)	General Service Demand Recovery [$]	109,575	109,186	115,884	155,380	91,883	83,457	100,699	80,001
(17)	Amount Billed to SC Customers [$]	221,451	206,142	203,806	284,521	215,767	200,936	202,397	155,055
(18)	Over (Under) Recovery [$]	41,895	20,763	7,250	42,299	(49,501)	(74,277)	(14,317)	(26,727)
(19)	Cumulative Over (Under) Recovery [$]	409,282	430,044	437,295	479,594	430,093	355,816	341,499	314,772

Line		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
(20)	Estimated SO2 Expense [$]	51,790	100,581	49,272	37,437	30,436	10,384	17,381	32,825
(21)	Estimated Ammonia & Limestone Expense [$]	1,586,323	2,248,084	2,886,869	2,334,741	1,808,564	1,011,071	1,299,290	2,655,698
(22)	Estimated NOx Expense [$]	24,392	43,659	26,781	20,618	16,799	9,520	23,657	42,344
(23)	Estimated Off-System Sales [$]	(16,013)	(17,130)	(47,086)	(49,626)	(56,857)	(126,119)	(68,975)	(70,157)
(24)	Estimated Total Environmental Expense [$]	1,646,492	2,375,194	2,915,836	2,343,170	1,798,942	904,855	1,271,353	2,660,711
(25)	Estimated SC Allocation Factor of Total Expense	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775	0.11775
(26)	SC Share of Total Environmental Expense [$]	193,874	279,679	343,340	275,908	211,825	106,547	149,702	313,299
(27)	Residential kWh	116,265,563	197,851,029	267,943,839	208,611,988	166,992,075	115,348,736	115,356,886	173,262,561
(28)	Residential Recovery Rate	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
(29)	Residential Recovery [$]	58,133	98,926	133,972	104,306	83,496	57,674	57,678	86,631
(30)	General Service (Non-Demand) kWh	17,505,225	21,827,248	25,685,794	24,782,608	22,971,347	20,476,328	19,962,077	25,466,713
(31)	General Service (Non-Demand) Recovery Rate	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
(32)	General Service (Non-Demand) Recovery [$]	8,753	10,914	12,843	12,391	11,486	10,238	9,981	12,733
(33)	General Service Demand kW	750,505	827,187	689,527	823,509	868,051	731,238	650,307	870,306
(34)	General Service Recovery Rate	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
(35)	General Service Demand Recovery [$]	90,061	99,262	82,743	98,821	104,166	87,749	78,037	104,437
(36)	Amount Billed to SC Customers [$]	156,947	209,102	229,558	215,518	199,148	155,661	145,696	203,801
(37)	Over (Under) Recovery [$]	(36,927)	(70,577)	(113,782)	(60,390)	(12,677)	49,114	(4,006)	(109,498)
(38)	Cumulative Over (Under) Recovery [$]	277,845	207,268	93,486	33,096	20,419	69,533	65,527	(43,971)

Barkley Exhibit No. 10
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2012-1-E
CALCULATION OF TOTAL FUEL COMPONENT
For the Year Ending June 30, 2013

		Cents / KWH				
Line	Class	Base Fuel Cost Component (from Exhibit No. 6)	Base Fuel Cost Component Increased For RECD	Env. Cost Component (from Exhibit No. 9)	Env. Cost Component Increased For RECD	Total Fuel Costs Factor
(1)	Residential	2.707	2.729	0.050	0.050	2.779 [2]
(2)	General Service (non-demand)	2.707		0.050		2.757
(3)	General Service (demand)	2.707		0.000 [1]		2.707
(4)	Lighting	2.707		0.000		2.707

[1] The environmental rate for these customers is 12 cents per kW as shown on Exhibit No. 9.

[2] RECD factor is .7927% and is calculated on Exhibit No. 12.

Barkley Exhibit No. 11
Docket No. 2012-1-E

PROGRESS ENERGY CAROLINAS, INC.
SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2012-1-E
Revenue Adjustment Factor

Residential Adjustment Factor

1	Billed kWh (12ME 2/28/12)	Per Books	2,150,668,275
2	Billed RECD kWh (12ME 2/28/12)	Per Books	340,965,808 (a)
3	RECD kWh Percent of Total Billed	Line 2 / Line 1	15.8539%
4	RECD Discount	RECD Discount	5.0000% (b)
5	RECD Impact (Weighted Discount)	Line 3 x Line 4	0.7927%

Notes:
(a) Energy billed and discounted pursuant to Residential Energy Conservation Discount, Rider RECD-2B.
(b) Five-percent discount provided under Residential Energy Conservation Discount, Rider RECD-2B.

STATE OF NORTH CAROLINA)
)
) **VERIFICATION**
)
) **DOCKET NO. 2012-1-E**
COUNTY OF WAKE)

PERSONALLY APPEARED before me, Dewey S. Roberts, II who, after first being duly sworn, said that he is Manager – Power System Operations - Carolinas at Progress Energy Carolinas, Inc. and as such is authorized to make this verification; that he has read the foregoing Testimony and knows the contents thereof; and that the same are true and correct to the best of his knowledge, information, and belief.

Dewey S. Roberts

DEWEY S. ROBERTS, II

Sworn to and subscribed before me,
this the 9th day of May, 2012.

Marsha H. Manning

Marsha H. Manning, Notary Public

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG2522

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2012-1-E
DIRECT TESTIMONY OF
PROGRESS ENERGY CAROLINAS, INC.

WITNESS DEWEY S. ROBERTS II

Q. Mr. Roberts will you please state your full name, occupation, and address?

A. My name is Dewey S. Roberts II (Sammy). I am employed by Progress Energy Carolinas, Inc. ("PEC" or "Company") as Manager – Power System Operations in the Transmission Operations and Planning Department. My business address is 3401 Hillsborough St, Raleigh, North Carolina.

Q. Please summarize briefly your educational background and experience.

A. I graduated from North Carolina State University in 1987 with a B.S. Degree in Electrical Engineering. I also obtained a Master of Science Degree in Electrical Engineering from North Carolina State University in 1990 and a Master of Business Administration Degree from North Carolina State University in 2004. I am a member of the Institute of Electrical and Electronics Engineers (IEEE). I am also a registered Professional Engineer in the state of North Carolina and I am recognized as a Certified System Operator by the North American Electric Reliability Corporation. I joined the Company in 1990 and have held several engineering and management positions in Nuclear Engineering, Engineering and Technical Services, System Operator Training, Portfolio Management, Transmission Services, and Power System Operations. These positions include: Project Engineer, Manager - Transmission Services, and Manager - Power System Operations. In November 2003, I assumed the position of Manager – Power System Operations in the Power

System Operations Section of Progress Energy Carolinas, Inc. System Planning and Operations Department. In my current position as Manager - Power System Operations, I am responsible for managing the safe, reliable, economic, and North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC") and environmentally compliant operations for the Progress Energy Carolinas' eastern and western balancing authority area power systems.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the operating performance of the Company's nuclear, coal, combined cycle, combustion turbine, and hydroelectric generating facilities during the period of March 1, 2011 through February 29, 2012 and demonstrate that PEC prudently operated its system for the period under review.

Q. Describe the types of generating facilities owned and operated by the Company.

A. The Company owns and operates a diverse mix of generating facilities consisting of four (4) hydro plants, forty five (45) combustion turbines, two (2) combined cycle units, sixteen (16) coal-fired generating units, and four (4) nuclear units.

Q. Why does the Company utilize such a diverse mix of generating facilities and resources for providing electric service?

A. There are two reasons PEC, and all utilities, rely upon a diverse mix of resources to meet their customers' needs. The first reason is the timing and amount of electricity consumed by its customers. This is often referred to as load shape. Different types of resources are used to meet customer demand depending on how often a resource is forecasted to operate during the year. The second reason is fuel diversity. A diverse mix of fuel types ensures that reliability is not jeopardized if a fuel becomes in short supply, and that if the cost of one type of fuel increases, other less expensive fuels can be used in its place.

Each type of generating facility has different operating and installation costs and is generally intended to meet a certain type of loading situation. In combination, the diversity of the system, in conjunction with power purchases made when doing so is more cost-effective than using a Company owned generating unit, allows the Company to meet the continuously changing customer load pattern in a reasonable, cost-effective manner.

Q. Please describe the intended use of each type of generation facility.

A. As a general rule, peaking resources such as combustion turbines, are constructed with the intention of running them very infrequently, i.e., only during peak or emergency conditions. They have low installation costs as compared to other forms of generation resources, and historically have had much higher fuel costs. Combustion turbines are very effective in providing reserve capacity because they can be started quickly in response to a sharp increase in customer demand, without having to continuously operate the units. During the review period, in order to minimize PEC's fuel costs, PEC took advantage of the dramatic decrease in natural gas prices and operated its natural gas-fired combustion turbines at much higher capacity factors as compared with prior review periods.

On the other end of the resource spectrum are PEC's baseload plants which are intended to meet the constant level of demand on the system. These are PEC's large coal units and nuclear plants. These plants have relatively high installation costs as compared to combustion turbines, but historically lower operating costs. The Company's four nuclear units, four Roxboro Plant coal units, the Mayo Plant coal unit, and two Asheville Plant coal units constitute its baseload facilities. Baseload facilities are intended and designed to operate on a near continuous basis with the exception of outages for required maintenance, modifications, repairs, major overhauls, or for refueling in the case of nuclear plants.

Designed to be dispatched in between PEC's baseload and peaking resources are PEC's intermediate load following facilities. These facilities are PEC's smaller coal-fired units and our Richmond County CC4 and CC5 combined cycle natural gas-fired units. These intermediate facilities are intended to operate in a load following manner with periodic startups. The intermediate coal-fired units are best utilized to respond to the more predictable system load patterns because the intermediate coal-fired facilities take some time to bring on-line from a cold shut down state. Gas-fired combined cycle units take less time to bring on-line from a cold shut down state. During the review period, due to the dramatic decrease in natural gas prices and the generator efficiency of our Richmond County combined cycle units, these combined cycle units were operated in more of a baseload manner and often were dispatched before PEC's large baseload coal units.

Based on the load level that the Company is called on to serve at any given point in time, the Company selects the combination of facilities and power purchases which will supply electricity in the most economical manner, giving due regard to reliability of service and safety. Demand side management programs such as air conditioner, water heater, and heat strip controls are utilized during peak load periods when capacity margins warrant their use to ensure reliable service and displace the need for installation of additional peaking generation resources or power purchases. This total cost optimization approach provides for overall minimization of the total cost of providing electric service.

In addition, prudent capacity margin planning through an effective integrated resource planning (IRP) process provides the Company with reserve resources needed to continue to provide safe and reliable service in periods when generation resources may be forced off-line. This IRP process includes consideration of power purchases, self-build options, and demand side management and energy efficiency programs.

Q. Have any unit uprates, derates, additions or retirements occurred in the 12 month period ending February 29, 2012?

A. Yes, on an annual basis the Company validates the dependable capability for our generators and reflects these validated capacities in the Company's Integrated Resource Plan (IRP). In addition, the generator fleet capabilities reflected in the IRP include uprates, derates, additions, and retirements for PEC generation. With respect to unit additions and retirements, for the 12 month period ending February 29, 2012, the Company added the Richmond County CC5 combined cycle generator with summer and winter capacity ratings of 652 MW and 708 MW respectively. During the review period, PEC retired the Cape Fear 1 Steam

Turbine, Cape Fear 2 Steam Turbine, and Weatherspoon Plant Units 1, 2, and 3. The total summer rating capacity retired in the aggregate was 188 MWs.

The transition from older coal-fired units to new combined cycle gas-fired units is a result of our IRP process that includes consideration of retrofits and additions of clean air equipment that would have been required to comply with federal regulations. This transition also places the Company in a good position to take advantage of increased natural gas supplies and resulting lower natural gas prices. This transition will continue through 2013.

Q. How much electricity was generated by each type of Company generating unit in the 12 month period ending February 29, 2012?

A. For the twelve-month period ending February 29, 2012, the Company generated 58,275,560 megawatt hours of electricity. Nuclear plants generated 48.19%, coal plants generated 35.74%, combined cycle and combustion turbine units generated 14.93%, and hydroelectric units generated 1.14% of the total amount of electricity generated.

Q. How does the Company ensure that it operates these types of generating facilities as economically as possible?

A. The Company has a central Energy Control Center which monitors the electricity demands within our service area. The Energy Control Center regulates and dispatches available generating units in response to customer demand in a least cost manner. Sophisticated computer control systems match the available sources of power with changing electric demand. Personnel at the Energy Control Center, in addition to being in contact with the Company's generating plants, are also in communication with other utilities bordering our service territory. In the event a plant is suddenly forced off-line, the interconnections with neighboring utilities help to ensure that service to our customers is uninterrupted. Additionally, the interconnections allow us to purchase power from neighboring utilities with unloaded capacity so that our customers will be served by the lowest cost power available that can be reliably delivered to the Company's power system.

Q. How does the Company determine when it needs to purchase power?

A. The Company is constantly reviewing the power markets for purchase opportunities. PEC buys power when there is reliable power available that is less expensive than the marginal cost of the Company's available resources. A comparison of the marginal cost of the Company's available resources versus the price of available market power is performed as frequently as every 5 minutes in order to assess and take advantage of economic purchase opportunities. Also, with regard to long term resource planning, the Company always evaluates purchased power opportunities against self build options.

Q. During the review period March 1, 2011 through February 29, 2012, did the Company prudently operate its generating system within the guidelines discussed in regard to the three types of facilities?

A. Yes. Two different measures are utilized to evaluate the performance of generating facilities. They are equivalent availability factor and capacity factor. Equivalent availability factor refers to the percent of a given time a facility was available to operate at full power if needed. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based on its maximum dependable capacity. Equivalent availability factor describes how well a facility was operated, even in cases where the unit was used in a load following application.

Our combustion turbines averaged 83.96% equivalent availability for the review period. These units' capacity factor was 6.65% which is higher than normal for the reasons I explained earlier. Low natural gas prices made it cost effective to operate these plants ahead of our older coal plants. These performance indicators are consistent with the combustion turbine generation intended purpose.

Our Richmond County combined cycle units had an average equivalent availability of 93.14% and a capacity factor of 72.86% for the twelve-month period ending February 29, 2012. The increased capacity factor compared to prior review periods reflects the gas-fired combined cycle unit's taking advantage of lower gas prices to reduce our fuel costs. Our intermediate (or cycling) coal fired units, had an average equivalent availability factor of 88.68% and a capacity factor of 27.36% for the twelve-month period ending February 29, 2012. This lower capacity factor reflects PEC's greater use of its natural gas fired generation due to the current low natural gas prices. These performance indicators are indicative of good performance and generation resource management.

Our baseload coal units had an average equivalent availability of 89.67% and a capacity factor of 72.21% for the twelve-month period ending February 29, 2012. Thus, these baseload coal units were also well managed and operated.

For the twelve-month period ending February 29, 2012, the Company's nuclear generation system achieved an actual capacity factor of 91.77%. Excluding outage time associated with reasonable outages, such as refueling outages, the nuclear generation system's net capacity factor for this period rises to 101.8%. Therefore, pursuant to S.C. Code Ann. § 58-27-865(F), since the adjusted capacity factor exceeds 92.5%, the Company is presumed to have made every reasonable effort to minimize the cost associated with the operation of its nuclear generation.

Q: How did the performance of the Company's nuclear system compare to the industry average?

A: During the review period of March 1, 2011 through February 29, 2012, the Company's nuclear generation system achieved an actual capacity factor of 91.77%. In contrast, the NERC five-year average capacity factor for 2006-2010 for all commercial nuclear generation in North America was 89.59%. The Company's nuclear system incurred a 2.39% forced outage rate during the twelve-month period ending February 29, 2012 compared to the industry average of 2.34%. These performance indicators reflect that the Company's nuclear performance for the review period is consistent with or better than the industry five year average. Thus, the Company has demonstrated good nuclear fleet performance during the March 1, 2011 through February 29, 2012 review period.

Q. How did the Company's coal units perform as compared to the industry?

A. Our entire coal-fired generation fleet operated well during the 12 months ending February 29, 2012, achieving an equivalent availability factor of 86.62% for this period. This performance indicator exceeds the most recently published NERC average equivalent availability for coal plants of 83.61%. The NERC average covers the period 2006-2010 and represents the performance of 921 coal-fired units.

Equivalent availability is a more meaningful measure of performance for coal plants than capacity factor because the output of our coal units varies significantly depending on the level of system load. For the twelve-month period ending February 29, 2012, our baseload coal units Asheville 1 and 2, Mayo Unit 1, and Roxboro Units 1, 2, 3, and 4, operated at equivalent availabilities of 82.33%, 87.80%, 90.05%, 70.86%, 70.93%, 91.71%, and 98.84% respectively. The Roxboro Units 1 and 2 equivalent availabilities are low relative to the NERC average equivalent availability primarily as a result of a major boiler overhaul outage and a major condenser tube replacement outage for units 1 and 2 respectively.

As I mentioned earlier, the baseload coal units achieved an average equivalent availability of 89.67%. These performance indicators compare well with the industry average equivalent availability factor of 83.43% for 306 similarly sized coal units.

Q. How did the Company's gas-fired combined cycle units perform during the review period as compared to the industry?

A. The gas-fired combined cycle units are the most efficient thermal units in the PEC generation fleet. This efficiency allows our combined cycle units to take advantage of low natural gas prices and as mentioned previously, has allowed our Richmond County combined cycle units to operate in a baseload manner. The gas-fired combined cycle units achieved an average equivalent availability of 93.14% and a capacity factor of 72.86%. These performance indicators compare well with the

NERC 2006-2010 five year industry average equivalent availability of 87.17% and capacity factor of 37.40% for 187 combined cycle generation units.

Q. How did the Company's hydroelectric units perform during the review period?

A. The usage of the hydroelectric facilities on the Company's system is limited by the availability of water that can be released through the turbine generators. The Company's hydroelectric plants have very limited ponding capacity for water storage. The Company operates the hydroelectric plants to obtain the maximum generation from them; but because of the small water storage capacity available, the hydroelectric units have been primarily utilized for peaking and regulating purposes. This operation maximizes the economic benefit of the units. The hydroelectric units had an equivalent availability of 95.74% and operated at a capacity factor of 33.26% for the twelve-month period ending February 29, 2012. The 5 year industry average for hydroelectric generation as published in NERC's most recent report reflects an average equivalent availability of 84.93% and an average capacity factor of 39.86%. These performance indicators show that the Company managed the hydroelectric facilities better than the industry 5 year average for hydroelectric generation equivalent availability, keeping them almost always available for economic use when water was available.

Q. Are you presenting any exhibits with your testimony?

A. Yes. Roberts Exhibit No. 1 is a graphic representation of the Company's generation system operation for the twelve-month period ending February 29, 2012.

Q. Did the Company prudently operate and dispatch its generation resources during the period March 1, 2011 through February 29, 2012 in order to minimize its fuel costs?

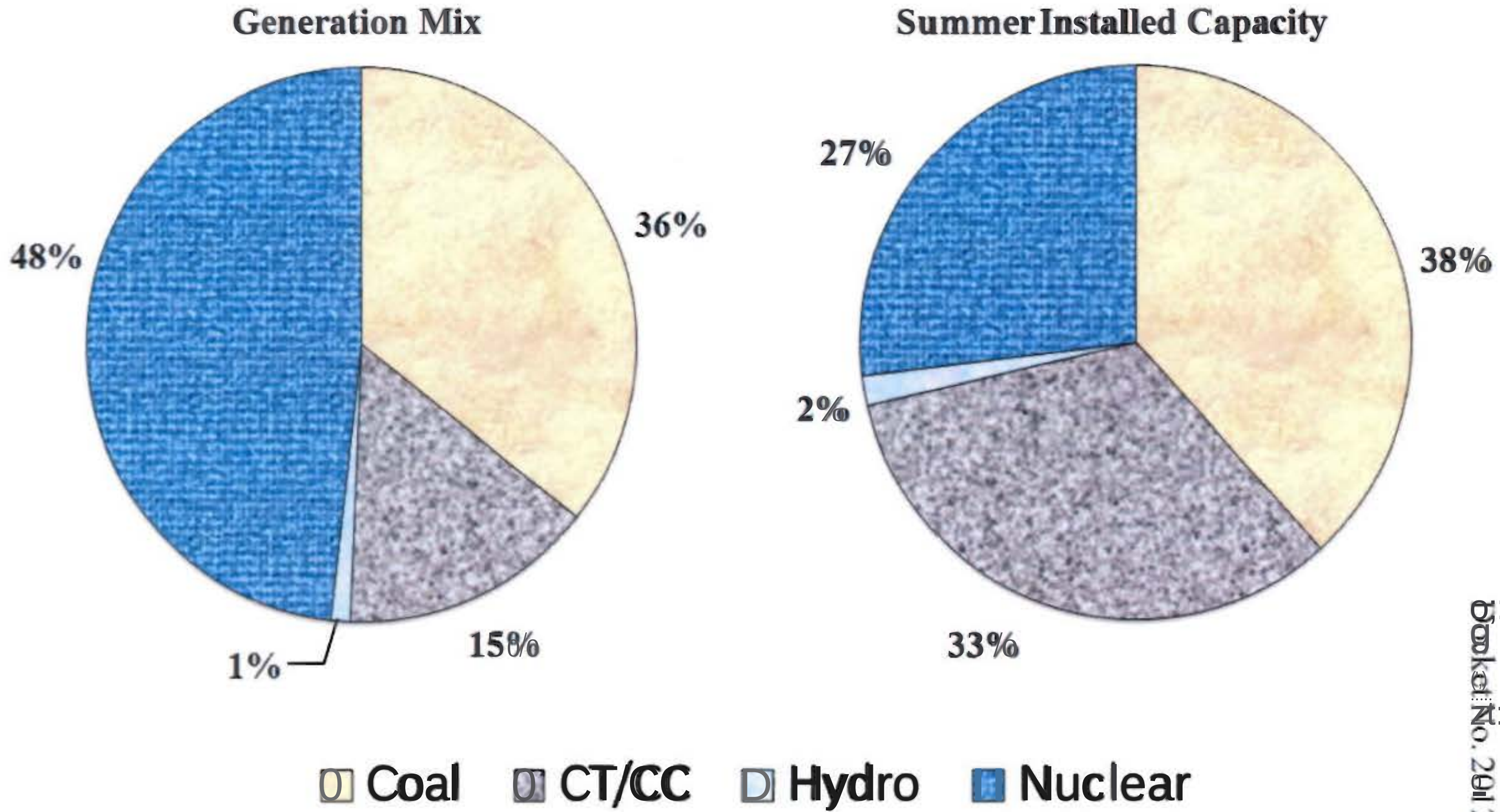
A. Yes.

Q. Does this conclude your testimony?

A. Yes.

213191

Comparison of Progress Energy Carolinas
Installed Generating Capacity
to Actual Generation Mix
March 1, 2011 through February 29, 2012



Roberts Exhibit No. 1
Docket No. 2012-1-E

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKETING DEPARTMENT

NOTICE OF FILING

DOCKET NO. 2012-1-E

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC. - ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS.

S.C. Code Ann. Section 58-27-865 (Supp. 2004) established a procedure for annual hearings to allow the Commission and all interested parties to review the fuel purchasing practices and policies of the Company and for the Commission to determine if any adjustment in the fuel cost recovery mechanism is necessary and reasonable.

On May 9, 2012 Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("the Company") submitted testimony in support of a change in rates based solely on the cost of fuel during the period March 1, 2011 through February 29, 2012 and forecasted cost of fuel for the period from March 1, 2012 through June 30, 2013.

The Company has requested that the Commission reduce the base fuel factor established in Docket No. 2011-1-E by .334 cents per kWh. The current base fuel factor is 3.041 cents per kWh, and the reduction is the difference between the current factor and the requested factor of 2.707 cents per kWh.

For the Residential class, the Company requested that the Commission decrease the environmental cost component by .014 cents per kWh. The current environmental cost component is .064 cents per kWh, and the decrease is the difference between the current factor and the requested factor of .050 cents per kWh. Additionally, the Company has requested that its residential base fuel factor be increased by .022 cents per kWh to account for discounts of 5% that are provided to residential customers served under Rider RECD-2B. The current amount related to the 5% discounts is .026 cents per kWh. The total reduction requested is .352 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.131 cents per kWh and the requested total fuel cost factor of 2.779 cents per kWh.

For the General Service (non-demand) class, the Company requested that the Commission decrease the environmental cost component by .011 cents per kWh. The current environmental cost component is .061 cents per kWh, and the increase is the difference between the current factor and the requested factor of .050 cents per kWh. The total reduction requested is .345 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.102 cents per kWh and the requested total fuel cost factor of 2.757 cents per kWh.

For the General Service (demand) class, the Company requested that the Commission decrease the environmental cost component by 6 cents per kW. The current environmental cost component is 18 cents per kW, and the increase is the difference between the current factor and the requested factor of 12 cents per kW.

For the Lighting class, the Company requested that the Commission make no change to the current environmental cost of .000 cents per kWh. The total reduction requested is .334 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.041 cents per kWh and the requested total fuel cost factor of 2.707 cents per kWh.

Public Service Commission of SC
Attention: Docketing Department
PO Drawer 11649
Columbia, SC 29211

Date: May 9, 2012